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RECENT TECHNOLOGICAL ADVANCES IN THE EXPLOITATION AND USE OF COAL RESOURCES

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1. Summary

The image of coal as unattractive fuel which is difficult to handle, burn and which produces troublesome wastes at various stages in the chain of coal use is being cut to rest. Its availability is unquestioned and its potential extensive.

The Nature of Coal

Coal is a highly variable, non-homogeneous fossilized material from an ancient plant world that has been converted as a result of exposure to high temperatures in the earth's crust over long periods of time, supplemented by the effects of pressure. It consists mostly of carbon compounds derived from plant organic matter but it also contains minerals and elements from the earth's crust. The degree of metamorphosis from living plants to peat, lignite, sub-bituminous coal, bituminous coal and finally anthracite represents the rank of the coal. As the rank increases so does the carbon content while the volatile matter contained in the coal decreases. The rank of a coal influences its composition and how it will behave during processing, although the relationship of a coal property to its rank can only be defined in broad terms even within the same coal deposit.

Just about all of the elements in the earth's crust have either been identified in coal or are likely to be present. The major elemental components of coal are carbon, hydrogen and oxygen. Of the other elements, silicon, sulphur, nitrogen, aluminium, iron, calcium and magnesium are predominant. The carbon combined with small amounts of hydrogen and oxygen, provides the structural integrity and most of the heat content of coal.

The total amount of mineral matter in coal varies considerably, but it is usually present in sufficient concentrations to be significant in any coal use. The most abundant minerals present in coal are the clay minerals (alumino-silicates), followed by sulphides, carbonates and silica.

The classification of different types of coal into operational categories for use internationally is difficult for two particular reasons:

- Divisions between coal categories vary between classification systems, both national and international, based on calorific value, volatile matter content, caking and coking properties, or some

combination of these criteria. Although the relative value of coals within a particular category depends on the degree of dilution by moisture and ash and contamination by sulphur, chlorine, phosphorous and certain trace elements, these factors do not affect the divisions between categories.

- Coal quality can vary, and it is not always possible to ensure that the descriptive and analytical information which is available is truly representative of the body of coal to which it refers.

3. Coal Resources and Reserves

Total world coal resources are so large (Table 1) that if all were recoverable, they could provide thousands of years of supply. While these figures may be reassuring at first glance, they do not provide much information on possible constraints to the development and exploitation of coal as a source of energy.

Table 1

World Coal Resources and Reserves
(Thousand million tonnes)

	Bituminous Coal and Anthracite	Subbituminous Coal	Brown Coal/ Lignite
Proved Reserves	774.6	721.6	323.5
Additional Resources	5164.4	3335.2	2159.6
Total Resources	6796.0	4056.81	2483.1
Proved Recoverable Reserves	487.7	143.0	251.1

Source: World Energy Conference, Survey of Energy Resources, 1980.

The IEA's World Coal Resources and Reserves Data Bank Service has undertaken a detailed study of coal deposits throughout the world, identifying those considered capable of playing a significant part in world coal supply and trade in the next 20 years. For practical purposes, a 20 year period is a reasonable planning horizon because:

- Any coalfield which will make a significant impact on the world market must already be well known and reasonably accessible to existing facilities. Undeveloped fields remote from ports, railways and centres of population are unlikely to play a significant role within 20 years.

- Any mining technology which will play a dominant part in 20 years time has already been invented and will take that long to spread through the industry.

For each of the significant coalfields an estimate has been made of the amount of coal which is accessible for working by current technology. Results of this work are summarized in Table 2 and published in the "Concise Guide to World Coalfields"*.

Comparison of data in Tables 1 and 2 indicates that only about 55 per cent of the proved recoverable reserves identified by the World Energy Conference are considered by IEA Coal Research to be accessible over the next 20 years. This implies that although actual reserves are not a constraint to development, existing technology and economics do limit the availability of even proved recoverable reserves.

According to Table 2, reserves in OECD countries account for about one third of the world's total accessible coal with the United States alone having over 20 per cent. African countries account for about 6.5 per cent of the total, most of which is in South Africa.

It is necessary to keep in mind, however, that the large reserves in the United States and other OECD countries are partly due to the extensive exploration which has taken place. In future years, non-OECD countries may greatly increase their share of total world accessible coal as the infrastructure necessary to enable the mining and transport of coal is developed.

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* Concise Guide to World Coalfields (IEA Coal Research, London, 1983)

[illegible]

[illegible]	[illegible]	[illegible]
TOTAL WORLD	[illegible]	[illegible]
AFRICA	[illegible]	[illegible]
Botswana	[illegible]	[illegible]
South Africa	[illegible]	[illegible]
Zimbabwe	[illegible]	[illegible]
Other Africa	[illegible]	[illegible]
OECD	[illegible]	[illegible]
Canada	[illegible]	[illegible]
United States	[illegible]	[illegible]
Australia	[illegible]	[illegible]
New Zealand	[illegible]	[illegible]
Japan	[illegible]	[illegible]
Austria	[illegible]	[illegible]
Belgium	[illegible]	[illegible]
France	[illegible]	[illegible]
Germany	[illegible]	[illegible]
Greece	[illegible]	[illegible]
Ireland	[illegible]	[illegible]
Turkey	[illegible]	[illegible]
Rest of OECD	[illegible]	[illegible]
Other OECD	[illegible]	[illegible]
ASIA	[illegible]	[illegible]
China	[illegible]	[illegible]
India	[illegible]	[illegible]
Other Asia	[illegible]	[illegible]
COMECON	[illegible]	[illegible]
EAST EUROPE	[illegible]	[illegible]
Eastern Europe	[illegible]	[illegible]
Poland	[illegible]	[illegible]
Rumania (East)	[illegible]	[illegible]
Other East + COMECON	[illegible]	[illegible]
CENTRAL & SOUTH AMERICA	[illegible]	[illegible]
Colombia	[illegible]	[illegible]
Mexico	[illegible]	[illegible]
Venezuela	[illegible]	[illegible]
Other C & S America	[illegible]	[illegible]

Source: World Coal Resources and Reserves Data Base, [illegible] Research)

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Resource Assessment

Assessment of coal resources [illegible] geologists and mining engineers. Several techniques [illegible] possible to deduce the overall structure of [illegible] with considerable accuracy from [illegible] seismic surveys [illegible] couple petrophysical logging [illegible] detail core samples [illegible] analytical methods, together with [illegible] application of geostatistics [illegible] great speed.

The precision with which [illegible] depends on two main factors:

- the inherent structure of the coal [illegible]

- the extent to which [illegible]

For example, a flat, thin, [illegible] can be evaluated with a [illegible] placed boreholes, whereas a [illegible] concealed at depth beneath [illegible] considerable degree of uncertainty.

4. Coal Production

Historical Overview

Trends in coal production [illegible] considerably between regions as [illegible] output grew by over six times between [illegible] increased only slightly over the same period. [illegible] coal production in the Centrally Planned Economies [illegible] rest and production in the rest of the world [illegible] virtually all of the growth in world coal production [illegible] took place outside OECD. As a result, the [illegible]

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the world's largest coal-producing group, accounting for almost 55 per cent of total world coal production, while the share of CPE coal production in world total coal output declined from 41 per cent in 1960 to 36 per cent in 1973.

From 1973 to 1981, total world coal output grew by 27 per cent. Coal production in the OECD during this period showed a comparable increase of almost 27 per cent, a significant acceleration from earlier trends. Thus, the share of OECD coal production in world total coal output has remained relatively constant around 36 per cent since 1973.

Table 3

World Total Coal Production by Regions
(Million tonnes)

	1960	1973	1978	1981
World Total	2600.5	3032.8	3498.8	3791.2
OECD	1073.2	1104.4	1185.9	1398.4
CPE	1420.2	1750.6	2068.7	2081.3
All others	107.1	177.8	240.2	311.5

Source: IEA/OECD Coal Statistics and U.N. Energy Statistics

The overall coal production trends as indicated by Table 3 cover both Hard Coal and Brown Coal. A more detailed picture is given in Table 4 for Hard Coal. No brown coal production is reported as taking place in Africa.

OECD hard coal production fell by 2.7 per cent from 1960 to 1973. Production then increased by 3.2 per cent from 1973 to 1978 but accounted for less than 10 per cent of the total world production increase during this period. However, in the years since 1978, OECD production has increased by 17 per cent, representing about 7 per cent of the total world increase between 1978 and 1981. Substantial production increases after 1973 were recorded in Australia and the United States which more than compensated for the reduction of two major OECD European producers (Germany and the United Kingdom). The bulk of the increase in non-OECD production from 1973 to 1981 was assumed by China (163 Mt), the USSR (95 Mt), India (45 Mt) and the Republic of South Africa (64 Mt). Together they represent about 90 per cent of the total world hard coal production increase between 1973 and 1981 (367 Mt).

Table 4

World Coal Production by Regions/Countries

(Million tonnes)

Regions/Countries	1960	1973	1978	1980	1981
TOTAL WORLD	1966.9	2183.0	2545.7	2718.0	2750.2
OECD (1)	935.8	910.5	940.9	1093.3	1097.9
Canada	6.4	12.3	17.1	20.2	21.7
United States	391.5	529.6	576.8	710.4	698.1
Australia	21.9	55.5	71.8	76.6	92.1
Germany	148.0	103.7	90.1	94.5	95.5
United Kingdom	196.7	130.2	121.7	128.2	125.3
Other OECD	171.3	79.1	63.3	63.6	65.1
NON-OECD (2)	1031.1	1295.1	1604.8	1634.8	1642.3
AFRICA	39.7	68.4	95.9	121.7	136.9
Botswana	-	-	0.3	0.4	0.4
South Africa	38.2	62.4	90.6	116.0	131.2
Zimbabwe	-	3.5	3.1	3.1	2.9
Other Africa	1.5	2.5	2.0	2.2	2.4
ASIA	486.6	557.1	756.9	767.6	780.2
China	420.0	430.0	593.0	574.0	593.0
India	52.6	77.9	101.5	109.1	123.1
Other Asia	14.0	49.2	62.3	64.5	66.1
USSR	355.9	461.2	501.5	492.9	510.0
EAST EUROPE	141.5	196.7	233.0	243.7	202.6
Czechoslovakia	26.2	27.8	29.2	28.3	27.2
Poland	104.4	156.6	192.6	173.1	163.0
Germany (GDR)	2.7	0.8	0.1	-	-
Other East Europe(3)	8.1	11.5	11.1	12.2	12.4
CENTRAL & SOUTH AMERICA	7.3	11.6	17.5	19.0	20.6
Colombia	2.6	3.0	4.8	5.3	5.3
Mexico	1.8	4.3	6.8	7.0	8.1
Venezuela	-	0.1	0.1	-	-
Other C & S America	2.9	4.3	5.9	6.5	7.2

(1) Source: IEA/OECD Coal Statistics
(2) Source: United Nations Energy Statistics
(3) Includes Bulgaria, Hungary, Rumania and Yugoslavia

The distinction between coking coal and steam or thermal coal is important in projecting coal demand and for related production and trade forecasts, because the big producers of coking coal are limited in number and the big consumers are major steel-producing countries.

Future Prospects

Given the amount of accessible coal in significant coalfields both within the OECD area as well as in non-OECD coal-producing areas, ultimate availability of coal is very large. Ample supply potential exists in existing and new mines in Australia, Canada, South Africa and the United States which could meet expanded coal demand. However, massive development of new coal production capacity and construction of the necessary infrastructure for coal transportation requires long lead times and without assured or firm expectations of substantial continuing growth in coal demand, the necessary investments may not be made. Therefore, actual coal production capacity will largely be determined by demand for coal.

Table 5

OECD Projected Coal Production
(Million tonnes of coal equivalent)

	1978	1980	1985	1990
Coking Coal				
OECD TOTAL	220.0	249.2	282.0	290.2
CANADA	17.2	13.8	25.9	28.6
UNITED STATES	80.2	104.7	120.1	120.1
AUSTRALIA	40.2	47.8	52.9	57.2
NEW ZEALAND	0.4	0.4	0.6	1.4
JAPAN	9.1	4.5	6.3	6.6
GERMANY	51.0	55.8	52.9	52.9
UNITED KINGDOM	12.4	6.5	7.2	7.2
OTHER EUROPE	15.6	16.3	16.1	16.2
Steam Coal				
OECD TOTAL	642.2	757.3	843.5	1022.1
CANADA	3.2	5.0	10.3	28.5
UNITED STATES	447.3	535.3	596.3	755.0
AUSTRALIA	26.4	38.1	66.1	76.8
NEW ZEALAND	1.6	1.8	2.6	3.8
JAPAN	10.3	12.0	12.4	13.3
GERMANY	37.0	32.5	44.3	45.8
UNITED KINGDOM	87.5	96.6	95.8	94.0
OTHER EUROPE	29.4	35.1	27.3	35.0

Sources: IEA/OECD Coal statistics and IEA Country Submissions (1980)

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As can be seen from Table 5, the United States will continue to be the largest single coal producer during the next ten years, providing 60 per cent of total OECD coal output. The country has available coal reserves large enough to support rapidly expanding domestic and export needs. Uncertainty in domestic electricity generation growth is the major constraint facing coal production.

Australia's share could also increase from 7 per cent of OECD output in 1981 to 12 per cent by 1990, providing 25 per cent of incremental coal production. Ample potential for expanded production from existing and new mines exists with the commercial groups involved seeking long-term contracts. Currently, a number of new mine development plans are under way in New South Wales and Queensland. The major constraint on developing new mines is the current reluctance of consumers to enter into long-term commitments with adequate pricing arrangements which would provide the basis for the investment to develop new mines and associated infrastructure.

Canada is projected to increase coal production from 35 Mtce in 1981 to 60 Mtce in 1990. Coal resources are estimated to be adequate to supply an increasing domestic demand and an expanded export market. A major factor is that the main coal resources are located in the middle west of the country, separated from current domestic markets in the east by long distances and from western exporting terminals by difficult terrain, underscoring the importance of mastering future transport cost development.

Coal production in OECD Europe is projected to show a moderate increase from 323 Mtce in 1981 to 380 Mtce in 1990, as Spain, Greece and Turkey foresee a substantial expansion of output, mainly of lignite. Most other countries are estimated to maintain their current production level. Japan's production level is estimated to be around 19 Mtce over the next ten years.

A number of non-OECD countries have the potential capability to supply future coal demand. The Republic of South Africa has large reserves available at competitive cost in the international market and is expected to increase its exports. Colombia is developing a coalfield near the Atlantic coast and has the potential to be a big supplier to OECD Europe in the 1990s. Botswana has geographically favourable coal seams and could enter the international market towards the end of the century, depending on solutions for the transportation

About 70 per cent of the internationally traded coal in 1981 was imported by OECD countries. Apart from OECD countries' own production, the main coal trade, OECD Europe mainly obtains coal from the United States, South Africa and Poland. About 13 million tonnes are exported to Asia, mainly to Japan, East Asia and by the Atlantic basin countries to Japan, mainly from South Africa.

On the export side, the United States is the largest coal exporter in the world. It exported 59.7 million tonnes of coal in 1981, of which 36 million tonnes were steam coal. Outside of the OECD, the republic of South Africa exported a record level of 29.4 million tonnes, which was 30 per cent above the 1979 level. Poland's coal exports, which had been growing sharply from 4.4 million tonnes in 1970 to 25.4 million tonnes in 1979, have begun to reduce production in the current year, and it was announced that exports and priority given to the home market.

Future Prospects

Trade in steam coal is a relatively new phenomenon and has been growing rapidly for many years only coking coal was traded on a large scale. Steam coal trade is expected to increase in response to the need to diversify away from oil, expansion of the world iron and steel industry, and the desire to increase the overall share of coal trade, while the demand for coal for electricity generation purposes will increase. Future trade in coal is expected to be dominated by the exporters in steam coal.

The Republic of South Africa has increased its coal exports from about 1.5 Mtce before 1977 to a record level of 29.4 Mtce in 1981. The development of the Richards Bay coal port in the early 1970s was a key factor in the expansion of South Africa's coal exports. Further expansion of the port is underway to increase current capacity to about 44 Mtce by the mid-1980s. Further expansion of coal exports to 65 Mtce by the mid-1980s was decided upon in September 1981 and could eventually reach a level of 80 Mtce in the 1990s.

Colombia is developing a coalfield near the Atlantic coast with production expected to start in 1984 and reach 15 Mtce in the early 1990s. Further development is projected toward the end of the century.

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As mentioned above, the entry of Botswana into the international coal market toward the end of this century depends on the solutions for the transportation issue. [illegible] construction of a 1,500 km railway and the upgrading of the port of Walvis Bay in Namibia.

The projected large potential increase in coal trade depends not only on potential growth in electricity and other industrial demand for coal but also on the ability of the importing countries to continue upgrading coal handling and inland transporation systems on time. Development of the necessary infrastructure at both ends is necessary for future expansion of coal trade.

6. Coal Transportation

The coal transportation infrastructure of the world can be divided into three categories: inland transport, ports and ships. The effective capacity of any coal transport system may, for a variety of reasons, be significantly less than the nominal capacity. It appears that inland transport infrastructure may give the greatest cause for concern in the longer term. The development of slurry pipelines may provide the best solution in areas where rail or barge transport proves to be inadequate.

7. Coal Prices

The distinct difference in price trends between coal and oil has been the main factor in explaining the relative use of these fuels in the industrial sector and particularly for electricity generation. In addition to the incentive provided by relative price movements, environmental considerations and ease of handling also promoted the shift away from coal, particularly given the less sophisticated technology available to control emissions from coal burning in the 1960s.

Following the considerable increase in oil prices after 1973, coal prices also tended to rise but at a slower rate. Coal's competitive advantage over oil increased dramatically after 1973 and was further accentuated by the more recent price increases in oil prices in 1979 and 1980. More recently, however, world coal prices have declined under depressed economic conditions and are unlikely to increase in the short term while the oil market remains calm.

On a thermal basis, the price of coal, including an allowance for freight is generally less than half the cost of fuel oil. Mine-mouth costs account for about half of the total delivered cost of coal, although substantial differences exist, depending on specific trading patterns. Roughly half the non-production-related costs are inland transportation costs to export terminals, with the remaining half being maritime transportation and handling charges both at loading and unloading ports.

Price will continue to be a determining factor in the pace at which coal use expands. Although current price relationships are such that coal enjoys a substantial competitive advantage, many potential purchasers are uncertain about how coal prices will evolve in the long run relative to oil prices, and are reluctant to undertake long term commitments to switch to coal. While it is impossible to predict future price developments for oil or coal with any certainty, a number of factors suggest that if coal markets continue to operate competitively, the delivered price of coal in constant dollars may not increase much, if at all, over the next 20 years.

B. Coal Mining

Coal Mining Techniques

Surface mining involves the excavation of earth and rock covering the coal seam which is located at a relatively shallow depth. Following the removal of the coal, the land surface is regraded to incorporate the previously removed overburden.

The level of coal recovery from surface mines is significantly higher than that from underground mines (85 per cent: 60 per cent). In addition, productivity is higher and the capital costs are typically about half those for underground mines. In many cases it is possible, by selective extraction, or even by special preparation of the surface of the coal seam, to significantly increase the quality of surface mined coal, whereas in a deep mined coal seam there is much less scope for flexibility in extraction.

Techniques for careful control of the mining operation to avoid pollution of the surrounding area together with reclamation of the mined site are well established. In many cases older mine sites are now being progressively restored.

There are two basic methods of underground mining, room and pillar and longwall. [illegible] to about 4 metres thick. However, room and pillar is [illegible] mining, basically because of the [illegible]

The width of the coal face is [illegible] mining equipment [illegible] pillars created between [illegible] ultimately sets a limit on the [illegible] restrictions on subsidence the final [illegible] method, the removal of the pillars [illegible]

Longwall mining [illegible] development work per tonne of [illegible] productivity rates for [illegible] The coal getting equipment [illegible] entire coal face. As the coal is [illegible] mined section behind the [illegible] section (often up to 15 [illegible]

Developments [illegible] better utilization of equipment, [illegible] jets, hydraulic powered and remote [illegible] designed to increase coal production [illegible] also underway to optimize the extraction [illegible] seam coal deposits.

Recovery Ratio

In the United States [illegible] surface mines is about 80 per cent and from [illegible] about 50 per cent. Thick, simple seams [illegible] ratios in excess of 95 per cent. The reason [illegible] the seam boundaries in a small [illegible] operator often does not recover [illegible] boundaries, because the coal [illegible] matter than the retained [illegible] will often have a lower recovery [illegible] certain thickness of coal is just [illegible] the surrounding material.

The recovery rate for underground mining is generally lower than for surface mining because a certain amount of coal must be left around access facilities and in the form of pillars around the perimeter of the property to support the roof and prevent subsidence.

Recovery rates for pillar mining can be as low as 40 per cent to about 80 per cent depending on the width and the number of the pillars. In the pillar mining method known as the room and pillar mining method, about 50 per cent is usually the recovery rate, including the coal that is left in the form of minerals in the seam, as it is not economical to mine. The greater the depth, the larger the pillar must be to support the weight of the

Recovery rates for longwall mining, on the other hand, are about 80 per cent. The capital cost of the face equipment is significantly higher than conventional mining methods. However, mining have been able to reduce the

To date, the experience with longwall mining in Australia has potential advantages in terms of productivity, safety, production and product quality, relative to the overall cost per tonne of coal, the advantages of a reduction in the number of underground personnel. Nevertheless, the high in some cases a barrier to its

Washing of coal is a beneficiation process that is generally by means of processes that have been tested for the for crushed coal in pipelines. These impact on coal beneficiation

Remote mining technologies are also The degree of control which the size distribution of the run-of- beneficiation.

9. Coal Combustion

Irrespective of the variety of coal types, there are basic differences which affect the use of coal. Coal is a solid fuel and without quite extensive treatment it cannot be pumped like oil. Every movement of coal requires mechanical plant (scrapers, conveyors, etc.) which are considerably more complicated than the pumps and pipelines associated with oil products. Because of the solid nature of coal, which causes considerable wear of equipment, coal plants generally require more supervision and maintenance than comparable oil plants.

Combustion of coal is less intense than that of oil and gas. Thus for many applications a larger coal-fired boiler is required for a given heat output. The difference in combustion characteristics is also significant when considering the conversion of an oil, or more importantly, gas-fired installation to coal.

The ash content of coal is far higher than that of oil and the ash must either be removed by pre-combustion treatment or, more usually, be collected and disposed of after combustion. This feature has tended to mitigate against the use of coal in smaller installations, partly because of the extra equipment required and partly for lack of space. Newly developing coal cleaning technologies, however, as well as small-scale but extremely effective ash collecting systems, offer the prospect of far easier control of ash emissions.

The advantages of using coal stem from its price compared with the price of oil and also from its widespread availability. As noted above, on a thermal basis, the delivered price of coal is a little less than half that of fuel oil. This margin is extremely important as it governs the extent to which the coal price can absorb the cost of treating the impurities, waste materials and pollutants in order to satisfy the various regulations governing the use of coal, and the extent to which coal can be transformed into a form which is as convenient to use as the fuel it replaces.

Conversion from Oil Firing to Coal

Generally the major problems for reconverting a coal designed unit which has been burning oil are economic rather than technical. They include whether

space is available for the reinstallation of coal handling and storage facilities, and whether equipment such as pulverizers, burners, electrostatic precipitators and ash handling facilities need to be reinstalled or replaced.

The direct firing of coal in a unit which was designed to burn oil involves a more extensive evaluation. Potential problems may include:

- Furnace size inadequate for more than 50 to 70 per cent of rating
- Excess air insufficient for complete coal combustion
- Gas velocity too high in convection bank causing erosion
- Tubes spaced too closely in convection bank permitting ash to bridge tubes
- Lack of provision for ash and slag removal
- Excessive temperature of gas entering convection bank causing slag formation and fouling
- Use of finned tubes on economizer not compatible with coal ash
- Preheater design incompatible with coal combustion
- Inadequate electrostatic precipitator capacity
- Inadequate control systems for coal combustion
- Lack of burners for coal firing
- Lack of coal handling system
- Inadequate fan power.

This formidable list may not be applicable in all cases, but it is sufficient to make conversion to direct coal firing completely infeasible in many cases.

The development of coal liquid mixtures is one way in which coal can be introduced in a form with which the customer can most readily identify. The coupling of coal gasification facilities to industrial boilers is never likely to be an economic proposition. However, the possibility of a centralized coal gasification facility providing fuel to a number of boiler installations should not be overlooked.

Some change in performance including output is to be expected in converting from oil to coal. The extent of the change is a function of the specific design and current use pattern. The extent of derating of a boiler originally designed for oil is approximately proportional to the quantity of coal to be burned. Estimates of derating for oil-designed boilers after conversion to various forms of coal firing vary from 0 to 30 per cent.

Coal Combustion Technologies

Depending on the application and size of furnace, a number of combustion technologies are in widespread use. For industrial systems, various types of stoker-boilers are generally used. Stokers mechanically transport coal onto a grate within a furnace and remove the ash after combustion. Table 2 characterizes various types of stokers.

Table 7

Characteristics of various types of stoker

	Typical Capacity Range (kg steam/hr)	Maximum Burning Rate (MJ/m²/hr)	Characteristics
Spreader			
Stationary and dumping grate	10,000–75,000	1.4	Capable of burning a wide range of coals, best ability to follow fluctuating loads, high fly ash carry-over, low coal space
Travelling grate	45,000–180,000	2.4	
Vibrating grate	10,000–45,000	1.7	
Underfeed			
Single or double retort	10,000–15,000	1.4	Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly ash carry-yet, suitable for continuous-load operation
Multiple retort	15,000–725,000	1.9	
Chain grate and travelling grate	10,000–45,000	1.4	Characteristics similar to vibrating-grate stokers as well as good ash-burning efficiency, reliable steaming capacity,
Vibrating grate	15,000–75,000	1.7	Low maintenance, low fly ash carry-over, ease of operation, variety of widely caking coals, automatic operation over entire range

1 kg. steam/hr = 1.0× MJ/hr
Source: Coal Handbook, R.A. Meyers ed.

For larger installations, particularly power stations, pulverized coal (-200 mesh) is burned. There are several methods of firing pulverized coal which are related to the location and position of the burners in the furnace. The type of firing method used depends mainly on the type and size of the boiler and the coal type. Pulverised coal-fired boilers can fire a wide range

of coals. Although bituminous coals are by far the most common fuels, everything from anthracite to lignite has been fired in utility-size pulverized coal units. The effect of the ash in the coal on the operation of the furnace is an important aspect of coal selection. Most pulverized fuel furnaces are of the 'dry-bottom' variety in which the ash is removed as a dry solid. It is therefore necessary that the ash fusion temperature of the coal must be sufficiently high to avoid the ash slagging (becoming liquid). With pulverized fuel firing about 80 per cent of the ash is contained in the flue gases leaving the rest as 'bottom-ash'. It is this fly ash, which under certain circumstances, sticks to the furnace walls and/or the water tubes. Blowers are often used on a regular basis to dislodge ash deposits and prevent excessive buildup. The presence of iron and alkalis in the ash increases its adhesion to the furnace walls and water tubes.

Coal characteristics affect fuel preparation for pulverized fuel firing (moisture/handling; mineral matter/grinding), furnace operation and reliability (rating, availability/maintenance). Declining coal quality in recent years has resulted in a greater quantity of fuel being required to produce the same heat input. This puts extra loads on the pulverizers and the electrostatic precipitators. In the United States, for example, between 1969 and 1977, the mean heat rate for large coal-fired plants rose from 9,500 KJ/kWh to 10,000 KJ/kWh. Alternatively, boilers have been unable to maintain their rated capacity.

The cyclone furnace has, in many applications, been the main alternative to a pulverized fuel furnace, and although it is now no longer being installed there are a large number still in use. The furnace walls are water-cooled and covered with refractory brickwork. The high gas temperatures melt the ash which forms as a liquid slag on the furnace walls. Most of the ash is retained in the slag layer so that fly ash production is minimised, reducing fouling problems and electrostatic precipitator requirements. The main disadvantage of the cyclone furnace is the high level of NOx formation which results from the high gas temperatures.

Recent developments in pulverized coal firing include the direct firing of pulverized coal on a small scale. If the coal is of high enough quality (low ash, low moisture content) it is possible to burn it without the support of an auxiliary fuel such as oil or gas.

Demonstrations are underway in a number of countries of the direct firing of pulverized coal in small boilers (10-20 MW) using coal prepared in a central facility and delivered by tanker to a sealed storage bin adjacent to the boiler. Substantial savings have been made in operation costs, in one case enabling the cost of converting a 10 MW unit operating for 5,000 hours a year to be recouped in two years. Providing adequate precautions are taken, pulverized coal can be transported, handled and stored in a safe manner. Demonstrations on boilers of about 10 MW are being evaluated in Europe.

The main advantages of this system over coal water mixtures is that there is no inert material accompanying the coal.

Fluidized Bed Combustion

Fluidized bed combustion of coal (FBC) is being developed as an alternative to stoker fired combustion for industry and pulverized coal combustion for electricity generation. Fairly small fluidized bed boilers and furnace type dryers (less than 20 MW), which operate at atmospheric pressure, have been commercially available in a number of countries for some time. The application of FBC to the generation of electricity is still under development.

A fluidized bed consists of a stream of gas flowing upwards through a dense bed of solid particles. As the gas flow rate increases so does the force exerted on the particles until the bed of particles appears to boil (bubbling bed). If the gas flow rate is increased further, the smaller particles become entrained in the gas stream and are removed. Increasing the gas flow even further causes all the particles to be transported from the bed. This latter stage is the principle of the circulating fluidized bed. The particles are subsequently separated from the gas in a cyclone and returned to the bed. Both bubbling and circulating fluidized bed combustion are under active development and are available in smaller sizes for the combustion of a variety of fuels including coal, washery wastes, wood chips and biomass.

Coal mixed with limestone is supplied continuously to the bed, and the ash remaining after combustion is removed to keep the volume constant. Because of rapid mixing and the high rate of coal combustion, the

Table 7

Comparison of Bubbling and Circulating AFBCs
for Utility Applications

Characteristic	Type of FBC: Bubbling	Circulating
Largest Existing Unit (MWe)	20	30
Combustion Efficiency	99.0	99.9
Ca:S for 90% SO_2 removal	2.0	1.5
NO_x, lb/10^6 Btu	0.4	0.4
Feed points per 100 MW		
Coal	6 shovers	2 pneumatic
Limestone	2	2
Auxiliary Power, % of gross	5	6
Steam generator Cost Ratio	1.0	1.05 to 1.15

Source: Electric Power Research Institute

The ability to use coal (and other fuels) with a high proportion of inert material makes fluidized bed combustion an attractive option for burning residues from coal preparation such as flotation tailings. Trials have been underway in Australia, Germany and the U.K. for some years resulting in the successful combustion of washery wastes by fluidized bed combustion.

The possibility of fluidized bed plants operating in conjunction with coal preparation plants, producing clean low sulphur coal at minimum cost, or coal-water mixtures, together with electricity or steam from the refuse high sulphur material, is one which is being considered in a number of countries, both on economic and on environmental grounds.

The advantages of fluidized bed combustion which are evident for large boiler plants, such as not requiring the installation of flue gas desulphurization and also the smaller size of boiler for a given output, are not, however, generally applicable to small industrial applications. These units operate on low sulphur fuels and so far, in most cases, do not require flue gas desulphurization anyway. Although at the moment low sulphur coal does not command much of a premium price, this may change thus favouring fluidized bed combustion.

Fluidized bed combustion is commercially available in a number of countries on the same basis as other boilers. The maximum size so far installed is about 130 MW and many of the installations have been designed to use what would otherwise be waste materials such as washery wastes or wood chips.

Although fluidized bed combustion with limestone addition can remove sulphur, this in itself creates a significant amount of solid waste material for subsequent disposal (this material may be used in the building industry if the sulphur content is not too high). When burning a high sulphur (4 per cent) coal for example and removing 90 per cent of the SO_2 formed during combustion, up to 400 tons per hour of spent limestone would be produced from a 1000 MW power plant. Hence there is a significant incentive to develop systems that reduce the production of limestone sorbent and spent solids.

Recent investigations by EPRI suggest that atmospheric fluidized bed combustion which includes recycling of the bed material reduces limestone consumption, improves boiler and combustion efficiency and reduces capital and bus bar costs to the point that atmospheric fluidized bed/recycle systems are considered to be competitive with pulverized coal-fired systems with flue gas desulphurization using both high and low sulphur coal.

As well as varying the extent of fluidization, combustion can either take place at atmospheric pressure (AFBC) or under a pressure of 5 to 20 bar (PFBC).

Pressurised fluidized bed combustors of the bubbling-bed type are being primarily developed for the generation of electricity. The combustor operates at a high pressure, supplied via a gas turbine-driven air compressor. While the major part of the energy in the hot, pressurised exhaust gas is expended driving the air compressor, any excess energy can be used to generate electricity in a gas turbine to supplement that generated in a steam turbine in the normal way. A PFBC therefore can be operated in a combined cycle mode at an overall efficiency of about 40 per cent compared to about 35 per cent efficiency for a pulverized coal power plant equipped with a wet scrubber for removing SO_2.

In addition to the advantages normally associated with fluidized bed combustion, PFBC offers even further reduced boiler sizes which should permit

factory assembly even for quite large units, and a relatively simple concept relative to other combined cycles.

However in developing PFBC for commercial use, a number of issues must be satisfactorily resolved. These include:

- Efficient clean up of the hot gases prior to passing them over a turbine.
- Development of turbine blade materials for this application.
- Avoidance of erosion and corrosion of boiler tubes.
- Integration of combustor and gas turbine.
- Scale-up to utility plant size.

An alternative to the gas turbine combined cycle is the development of the turbocharged boiler which is based on PFBC but which has a much reduced gas turbine inlet temperature when compared to the combined cycle. The lower temperatures result in less stringent metallurgical demands and consequent improved reliability of the gas turbine and simplified structural design.

The turbocharged boiler, however, is not as efficient as a combined cycle plant, since there is no excess energy in the combustion gases to generate electricity. The advantage may well lie in this technology being a first step towards PFBC combined cycle, enabling the hot gas clean-up and turbine materials problems to be resolved separately.

Pressurised fluidized bed combustion technology for electricity generation is being pursued in two basic concepts; air cooled and steam cooled combustors for combined cycle generation of electricity. Variations on these two concepts such as using the gas turbine exhaust to support combustion in an AFBC to raise steam have also been studied, but so far little data has been accumulated.

Comparisons based on US Eastern and Western coals suggest that the cost of electric power from PFBC could cost up to 10 per cent less than that for a pulverized coal/flue gas desulphurization reference system. The costs for the

UK of fluidized bed combustion compared with pulverized coal firing for electricity generation have also been compared showing savings of a similar magnitude. There appear to be significant economies of scale for PFBC and conversely there are cost penalties associated with multimodular design. An air cooled PFBC system requires a much greater heat transfer surface than the steam cooled system and therefore on an equivalent thermal basis would be more expensive.

PFBC plant designs appear to be competitive with pulverized coal plant, but it should be noted that evaluations are so far based on preliminary design and operating data. There is no certainty that PFBC can meet stringent particulate emissions. The reliability of both hot gas clean up systems and pressurised fluidized bed combustors is being examined particularly in an IEA 80 MW (thermal) experimental facility built in the UK jointly by Germay, UK and US. The extent to which these and other tests are sufficient for subsequent commercial development remains to be seen. Also, the tolerance of gas turbines to particulate material in the hot gases has yet to be defined and demonstrated. Other advantages of PFBC over AFBC accrue on the environmental side. Less limestone is required for SO_2 removal and less NO_x is produced during pressurised fluidized bed combustion. On a very large scale (over 200 MW) PFBC is likely to be preferable to AFBC because of the greater (10 to 15 times) intensity of combustion.

Based on current developmental trends, however, it is unlikely that large scale PFBC (over 200 MW) will be available for utility use before 2000.

Coal Gasification - Combined Cycle

The major alternative development to the pulverized coal-fired boiler for electricity generation is to substitute coal gasification plant for the pulverized coal boiler. The production of medium calorific value gas (carbon monoxide and hydrogen) is possible by a number of different methods, some of which have been commercially available for many years, while others are still in the development stage. The gains in efficiency resulting from combined cycle generation of electricity are generally considered to be sufficient to offset the inherent losses associated with gasification of the coal. An additional advantage of combined cycle generation of electricity, relative to a conventional steam turbine of the same capacity, is the decrease of about 35 per cent in water requirements per unit of electrical output.

For use in a gas turbine, the raw gas from any gasification process must be cleaned of both particulate matter and alkali metal vapour to prevent fouling and erosion of the turbine blades, to minimise emissions to the atmosphere and to prevent solid particles interfering with the operation of the

The nature and concentration of the contaminants depend on the gasification process being used. In an A.F.B., 99 per cent efficiency in excess of 99.5 per cent will be required. If efficiency is to be maintained both gas clean-up and sulphur removal must take place while the gas is hot (with FBC, sulphur removal takes place during combustion). It has been estimated that hot gas treatment could increase overall plant efficiency by about 2 per cent. The alternative is to cool the gases to about 100°C, transferring the heat in them to water which is turned to steam as part of the feed to the steam turbine.

Table 10 shows the development of hot gas particulate removal processes.

Table 10

Hot Gas Particulate Removal Development
Operating Conditions

	Temp. °C	Pressure Bar	Removal Efficiency
Cyclone systems	650	5	99.9% (+40 micron), 5% (3 to 2.5 micron)
Multi-cyclone systems	650	50	99.4% (+5 micron), 50% (+2 micron)
Metal filters	870	50	100% (+ micron)
Fibre filters	650-1100	1	-
Fabric filters	370	1	99.5% (at ambient temp.)
Ceramic filters	760	1	100% (+ 1 micron)
Bed filters	870		99.5% of + 5 micron but may penetrate sub-micron particles
Electrostatic precipitator	800-1090	20	95% (+ 5 micron), 99.9% (0.75 micron)

Some of the nitrogen in the coal is converted to ammonia and can be readily removed from the synthetic gas by a straightforward scrubbing process. The air used for combustion is the other source of nitrogen. The formation of nitrogen oxide in the turbine combustor is suppressed by adding moisture to the clean syngas to hold down the flame temperature. The final solid wastes from gasification combined cycle plants are quenched slag from the ash in the coal and sulphur, drawn off which is straightforward.

The costs of combined cycle power plant compared with other processes are necessarily uncertain because of the stage of development of the processes and the consequent lack of information about system and component reliability. The 100 MW demonstration plant now under construction in the United States based on the Texaco gasification process with waste heat recovery cycle is designed to fulfill the objectives in constructing an integrated coal gasification combined cycle electric generating facility on a scale capable of demonstrating:

- Compliance with environmental regulations
- Operational flexibility and reliability
- Coal feedstock flexibility
- Integrated systems controls
- Alternative plant and process components.

The facility will assist in the establishment of operating, maintenance, safety and training procedures and in the development of precise economic criteria.

Coal-Liquid Mixtures

Despite coal's extensive price advantage over oil and gas, the relative inconvenience and increased capital costs associated with coal use and have largely limited coal to electric utility and larger industrial applications. The benefits of economies of scale in large facilities together with cheap fuel costs have tended to offset the high capital cost of ancillary equipment.

Overcoming the barriers to coal use will be greatly facilitated if the coal-based fuel is presented in a form similar to the fuel it is replacing. Coal/water mixtures (CWM) have the potential to lower the cost of using coal in medium size boilers and furnaces by providing the users with the convenience of a liquid which can be stored and distributed like oil and which can be easily retrofitted to existing boilers in a large centrally located facility.

Coal-oil mixture (COM) fuels are being tested in a variety of applications and a number of companies are proposing to supply COM on a commercial basis. However the current state of the oil market has reduced the economic attractiveness of COM in many countries with the notable exception of Japan. Coal water mixtures (CWM) are being developed and tested in a number of countries for a number of different applications in both boilers and furnaces. As well as testing combustion characteristics, development of preparation techniques minimising the quantity of stabilising additives required is underway.

Progress in recent years in fine coal cleaning has provided a considerable boost to the production of low ash, low sulphur fine coal for use in the CWM preparation. One of the attractions of CWM is that part of the water used in the grinding process can become the liquid phase of the slurry thus the dewatering stage in a coal cleaning system is a potential processing step to be eliminated. The preparation of low ash coal slurries could make it economic to convert oil fired boilers designed for oil firing could be easily converted to burn CWM with little or no de-rating, although the cost of the fine grinding required to enable most of the ash to be removed in order to avoid derating could, depending on the coal type, prove to be expensive.

The cost of converting boilers from oil to coal firing together with the attendant technical problems are the major drawbacks to fuel switching. Only a minority of the utility boilers originally designed to burn oil were built with coal-firing potential. Even the conversion of these boilers is likely to require considerable expenditure on coal handling equipment and on environmental control.

One of the major drawbacks of CWM is the extent to which the capacity of the boiler is reduced as a result of using a lower calorific value fuel and in the case of CWM the water which must first be evaporated. Conversion to CWM

firing would therefore generally entail keeping the original oil burning capability which may be required during start-up or at periods of low load (to maintain flame stability) or at maximum load to obtain the rated output of the boilers.

The ultimate development of COM may result in a fuel which is clean enough to be used in direct firing applications such as the brick and ceramic industries. In addition, low ash fluid coal made with ultrafine coal (less than 10 microns) may one day be suitable for use in gas turbines or even internal combustion engines. The particle size and size distribution is an important factor in preparing coal liquid slurries, particularly CWM where particle sizes down to 15 microns are being used.

Preparation of COM can be achieved in two basic ways; using pulverized coal with an additive to achieve a stable suspension and by using ultrafine ground coal, the preparation of which is expensive and depends to a large extent on coal type. COM needs to be warm when pumped and hot when atomized for combustion. Extensive tests with various coal:oil ratios have been carried out and generally little or no derating of conventionally shaped boilers occurs at coal concentrations of up to 50 per cent. There is, however, some derating of boilers with a relatively smaller volume than conventional configurations. NO_x emissions increase with increasing coal content and with the amount of excess air used. Emission of SO_x is dependent on the sulphur content of the fuel. Ash which is deposited during combustion is generally successfully removed by soot blowers which it is necessary to fit to the boiler. Erosion of the burners by the solid coal in the mixture has been lessened by providing hard facings to vulnerable areas.

Depending on the price and availability of oil, however, COM may turn out to be an interim fuel for industrial and utility use. Table 11 sets out the status of COM activities in the United States in 1982.

The more attractive proposition in the longer term is CWM in which all of the energy is provided by coal (even with a 50% by weight of coal in COM, only 40% of the energy is provided by coal). Following intensive cleaning of fine coal to less than 3 per cent ash and 1 per cent sulphur, the water content is adjusted to the 25 to 30 per cent range and the mixture is supplemented with additives to control the stability of the slurry and to reduce the viscosity. For extended periods of storage it is necessary to

Table 11

Company Institution	Location	Capacity	Status
Adelphi University			
Allied Oil Company			
American Refining Group Company			
ARCO			
Brookhaven Nat. Lab.			
Coastal Eagle Point Oil Company			
Coastal Corporation			
COMCO			
Columbia Fuels Coal Energy			
CRAMCO			
CRGON			
Florida Power			
(FPC			
Florida Power & Light Co. (FPL)			
Gulf-Western			
Interlake, Inc.			
Intermountain Coal			
Kylana Corporation			
MIT			
Mt. Airy Refining			
NEPCO			
Northeast Petro. Inc.			
Ohio Univ. of Athens			
PETC			
Tufts			
University of Nevada			
UOP Incorporated			
Wyatt Oil			

* - Completed

Source: US DOE

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Table 12 lists COM preparation plants in the United States.

Table 12

United States COM Preparation Plants
(1982)

Name of Company	Location	Capacity	Process Description
COMCo	Florida	2.5×10^3 bbl/day	Ultrafine coal; mechanical grinding
Island Creek Coal Co.	Florida	5.0×10^3 bbl/day	Standard grind (80% minus 200 mesh), plant is relocatable
Allied Oil Company	Ohio	1.5×10^3 bbl/day	Standard grind (80% minus 200 mesh), both dry and wet grinding techniques are used
Coalmaid, Inc.	Kentucky	1.2×10^2 bbl/day	80% minus 200 mesh, Cottrell Ultrasonic Process
Columbia Fluidized Coal Energy Corporation	Pennsylvania	0.4×10^2 bbl/day	Standard grind (80% minus 200 mesh)

Source: US DOE

Table 13

Status of CWM Activities in the United States
(1982)

Company/ Institution	CWM PREPARATION			CWM COMBUSTION		
	Activities R/D	Pilot Plant	Commercial Plant	R/D	Evaluation	Furnace
Alfred University/ ARCO	X X					
Atlantic Research	X	X	Planned	X	X	
COMCo	X					
ERGON	X	X(1)		X	X(1)	X(1)
Gulf-Western	X	X				
Island Creek Coal/ Occidental Research Co.	X					
MIT				X		
PETC	X	X		X	X	
Slurrytech, Inc./ B&W	X	X	Planned	X	X	

(1) ERGON developed and patented a coal pulverization process in which a fluid energy mill was used. The steam, a grinding medium, was also transported to the furnace. ERGON named it the coal/steam process.

Source: US DOE

A recently completed study in a number of IEA countries assessed the potential for COM utilization based on oil-fired utility and industrial boiler populations in each of the countries. The boiler populations were categorized by design, type, age and size. Average capacity factors were used in continuation with other parameters to estimate fuel oil consumption and the quantity of oil which could potentially be replaced by changing to COM or CWM.

In the six participating countries (Canada, Japan, Netherlands, Sweden, US) the following utility and industrial boiler population was ascertained (Table 14).

Table 14

Boiler Population

(a) Utility

Design	Number of Boilers	Output MW (e)
Coal	436	36920
Future Coal, Oil	55	10677
Liberal Oil	190	65452
Compact Oil	247	31672
Total	853	176821
Total (less than 20 years old)	484	141693

(b) Industrial

Design	Number	Input Capacity (MW(th))
Coal	148	14539
Modular/Field Oil	6727	229897
Package Water tube oil	19819	133750
Package Fire tube oil	140821	189522
Total	167515	567704
Total (less than 20 years old, over 3 MW)	1902	274605

Source: IEA CLM Project

In determining the magnitude of the potential market for CLM, boilers of less than 20 years old were considered possibilities for conversion and, in addition, in the industrial sector a lower limit of 3 MW(th) input was set.

The amount of oil which could be replaced by the utility sector switching to CWM is between 70 per cent and 85 per cent of the oil consumed depending on the amount of derating which is equivalent to about 700 million barrels a year in the six countries surveyed. The potential replacement of oil by COM or CWM in the industrial sector is about 480 million barrels per year in the case of CWM and about 210 million barrels per year in the case of COM representing about 50 per cent and 21 per cent respectively of the total oil consumed. The potential for African countries is unknown but it could well be that an equivalent proportion of the oil consumed in industrial and utility boilers could be replaced by coal-liquid mixtures.

In examining the economics of coal-liquid mixtures the gap between coal and oil prices (currently around $3 per GJ) must be sufficient to cover the costs of cleaning the coal, slurry preparation, transport and storage, boiler conversion and any derating of the boiler.

Pyrolysis

Pyrolysis, or the partial combustion of coal is one means of obtaining gaseous and liquid products from coal, leaving a residue of char which has some value as a fuel depending on the severity of the pyrolysis process. Pyrolysis can take place in an inert atmosphere or in an atmosphere which increases the amount and quality of the gaseous and liquid yields, such as hydrogen.

Depending on the ratio of organic to inorganic sulphur in the coal, and on the nature of the mineral constituents of the coal, the sulphur released during pyrolysis reacts with minerals in the coal to form sulphides. Thus after pyrolysis of a high sulphur coal, the sulphur content of the char may be high, but not much of it is released during combustion of the char (the sulphides are converted to sulphates which do not decompose until extremely high temperatures are reached). The sulphur which released with the gases is readily recovered with commercially available processes in the same way as with coal gasification (see above). The extent and mechanism of the elimination of sulphur is under examination by a number of researchers who are obtaining desulphurization during pyrolysis but to different extents and by different methods depending on the nature of the coal and reaction conditions, but particularly on the way the organic sulphur is bonded to the coal molecule.

However the pyrolysis process itself would seem to require further improvement, regardless of the extent to which it [illegible] a means of utilising high sulphur coals in a clean manner.

10. IEA Coal Research and Development

There are a number of collaborative R&D programmes aimed at the assessment and development of improved combustion techniques which are taking place under the umbrella of the IEA. These include the construction and operation of an 80 MW (thermal) pressurized fluidized bed combustion facility;

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